Transmission Business Line

Economic Analysis of Non-Transmission Alternatives

Feb 4th 2003

Agenda

- Introduction
- Non-transmission Alternatives
- Methodology
- Summary of Results
- Scenarios
- Conclusions

Introduction

Project Team

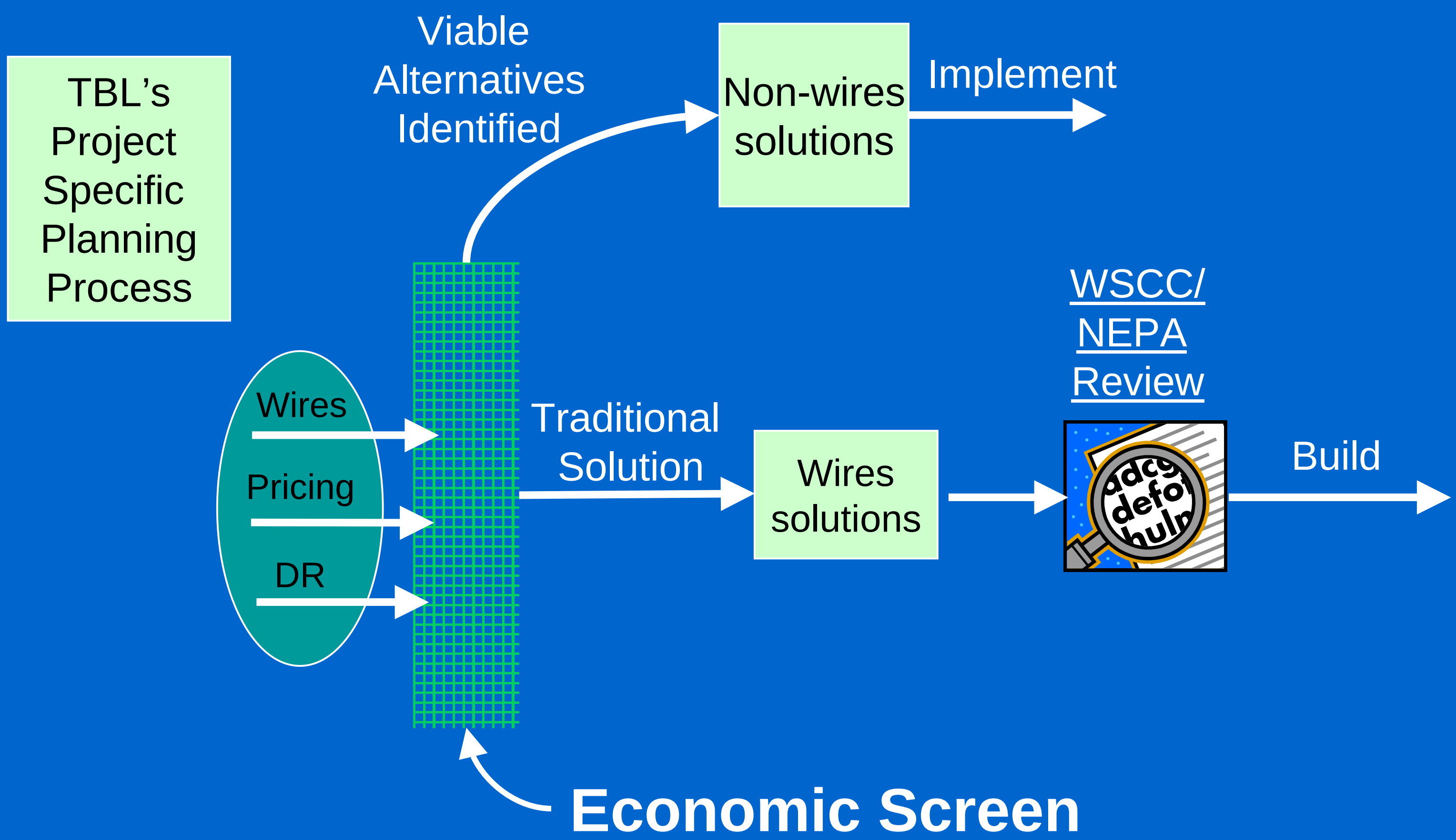
- Energy and Environmental Economics (E3)
- Awad & Singer
- Nexant, Inc.
- Tom Foley Consultants

Project Goals

- Identify technologies that would be cost effective alternatives to KEL
- Evaluate the sensitivity of the cost effectiveness analysis to variations in key input assumptions
- Estimate whether achievable load reduction from those cost effective alternatives would be sufficient to defer the line

Current Process

TBL Screen



Non-transmission Alternatives

Alternatives to Transmission Expansion

- Demand-side management measures
- Demand response programs
  - Price-based dispatch
  - Interruptible / curtailable and demand response contracts
- Generation and distributed generation

DSM Measures

- Typically considered energy efficiency measures rather than peak shaving programs

End Use	Residential	Commercial	Industrial	Other	TOTAL
Heating	108 (+ 16 AC)	2			126
Envelope	23	8			31
Lighting	21	652			673
Water Heating	16				16
Appliances	7	4			11
Exit Signs		7			7
Motors			657		657
Traffic Signals				10	10
Vending Machines				2	2
TOTAL	191	673	657	12	1,533

- DSM cost and performance measures from the Northwest Power Planning Council (NWPPC) Database

Demand Response Programs

- DR solutions directly address the capacity nature of the problem
  - Price-based dispatch programs offer customers incentives to voluntarily curtail load during the peak
  - Interruptible / curtailable rates or direct load control programs are pre-arranged contracts with customers and require a customer to reduce loads during the system peak for a fixed price at BPA's request

Generation and Distributed Generation

Generators should be available during heavy load hours when an outage would cause an overload on the Covington transformer banks

- Existing generation (not currently included in BPA power flow studies)
- New large-scale generation
- Existing distributed generation
- New distributed generation
- Regional availability of natural gas
- Renewable generation and emerging technologies

Existing and Potential Large Generators in the Puget Sound Area

Project	Location	Type	Available Capacity (Local MW)*	Effective MW at Covington
In service			*277*	*70*
Pierce Power	Frederickson	Gas turbine	154	31
Ross Dam**	Skagit River	Hydroelectric	109	46
BP Cherry Point GTs	Blaine	Gas turbine	73	23
Equilon GTs	Anacortes	Gas turbine	39	12
Georgia-Pacific GT	Bellingham	Gas turbine	11	4
Construction (Phase 1)			*268*	*56*
Frederickson Power 1	Frederickson	Combined-cycle	249	50
Tesoro (Permanent ICs)	Anacortes	Reciprocating engine	19	6
Permitted (Phase 2)			*1,156*	*365*
Sumas Energy 2	Sumas	Combined-cycle	660	211
Everett Delta I	Everett	Combined-cycle	248	77
Everett Delta II	Everett	Combined-cycle	248	77
Potential (Phase 3)			*1,643*	*460*
BP Cherry Point Cogen.	Blaine	Cogeneration	720	230
U.S. Electric Cherry Point	Blaine	Coal–Steam	349	112
Frederickson Power 2	Frederickson	Combined-cycle	280	56
Tahoma Energy Center	Frederickson	Combined-cycle	270	54
Cedar Hills	Cedar Hills Landfill	Landfill Gas	24	7
Maximum Available Puget Sound Area Generation			***3,344***	***950***

Generation Technologies Considered for High-Level Screening

	Combined Cycle Combustion Turbine	Simple Cycle Combustion Turbine	Cummins ORU Genset	Generic Diesel Engine	Gas Spark Ignition	Low Temp (PEM) Fuel Cell	High Temp Fuel Cell
Operating Data							
Heat rate	7,618	11,380	8,000	10,000	9,000	9,000	7,000
Lifetime (yrs)	25	25	25	25	25	25	25
Fuel	Gas	Gas	Diesel	Diesel	Gas	Gas	Gas
Avg. Fuel Cost	$3.90	$3.90	$6.09	$6.09	$3.90	$3.90	$3.90
Capacity Factor	90%	10%	10%	10%	10%	90%	90%
Smallest (kW)	50,000	500	1,000	500	300	1	1
Largest (kW)	750,000	50,000	5,000	10,000	5,000	250	250
Plant Costs							
Initial Cost ($/kW)	$523.06	$369.90	$558.32	$550.00	$550.00	$3,000.00	$4,000.00
Total Fixed Annual	$23.23	$11.14	$16.69	$16.61	$16.61	$16.61	$16.61
Fixed O&M ($/kW-yr.)	$18.00	$7.44	$11.11	$11.11	$11.11	$11.11	$11.11
Property Tax ($/kW-yr.)	$5.23	$3.70	$5.58	$5.50	$5.50	$30.00	$40.00
Variable O&M ($/MWh)	$0.60	$0.12	$3.50	$20.00	$15.00	$15.00	$10.00

Data Sources

- DSM Cost and Impact Information:
  - Northwest Power Planning Council (NWPPC) Database (http://www.nwppc.org/comments/default.asp)
- Direct Load Control Data:
  - “BPA Demand Response Program Research Report” Xenergy, Inc. September 2002, DRAFT, pp. 1-124. Follow up information on some utilities found on corporate websites.... names of the utilities were omitted from report
- Distributed Generation:
  - CADER Conference, DCPA Publication, Industry Contact
- Load Growth Forecast:
  - BPA Forecast of (small) Publics, Distribution Utility Forecasts (compiled by BPA), BPA TBL severe cold weather adjustment factor [based on Battelle Study]
- Load Flow Distribution Factors:
  - BPA TBL
- Transmission System Capability and Maximum Loadings:
  - BPA TBL
- Market Price Forecast:
  - Forward Market ["Assessment"] through 2005 [from Platts MW Daily], [April 2002 Draft Fifth Power Plan] Natural Gas [and distillate fuel oil] Forecast[s] is from Northwest Power Planning Council
- Transmission Line O&M Costs:
  - BPA TBL
- Existing Generation Resources:
  - NW Power Planning Council, "Existing Generating Projects" spreadsheet, http://www.nwcouncil.org/energy/powersupply/existingprojects.xls.
- New Generation Resources:
  - NW Power Planning Council, "Generating Project Development Activity" spreadsheet, http://www.nwcouncil.org/energy/powersupply/newprojects.xls.

Methodology

Methodology Overview

1. Start with base case transmission plan
2. Calculate required load reduction to defer or eliminate line and maintain reliability
3. Estimate maximum incentive payments based on the value of deferral
4. Calculate cost-effectiveness of non-transmission alternatives
5. Estimate penetration of cost-effective measures

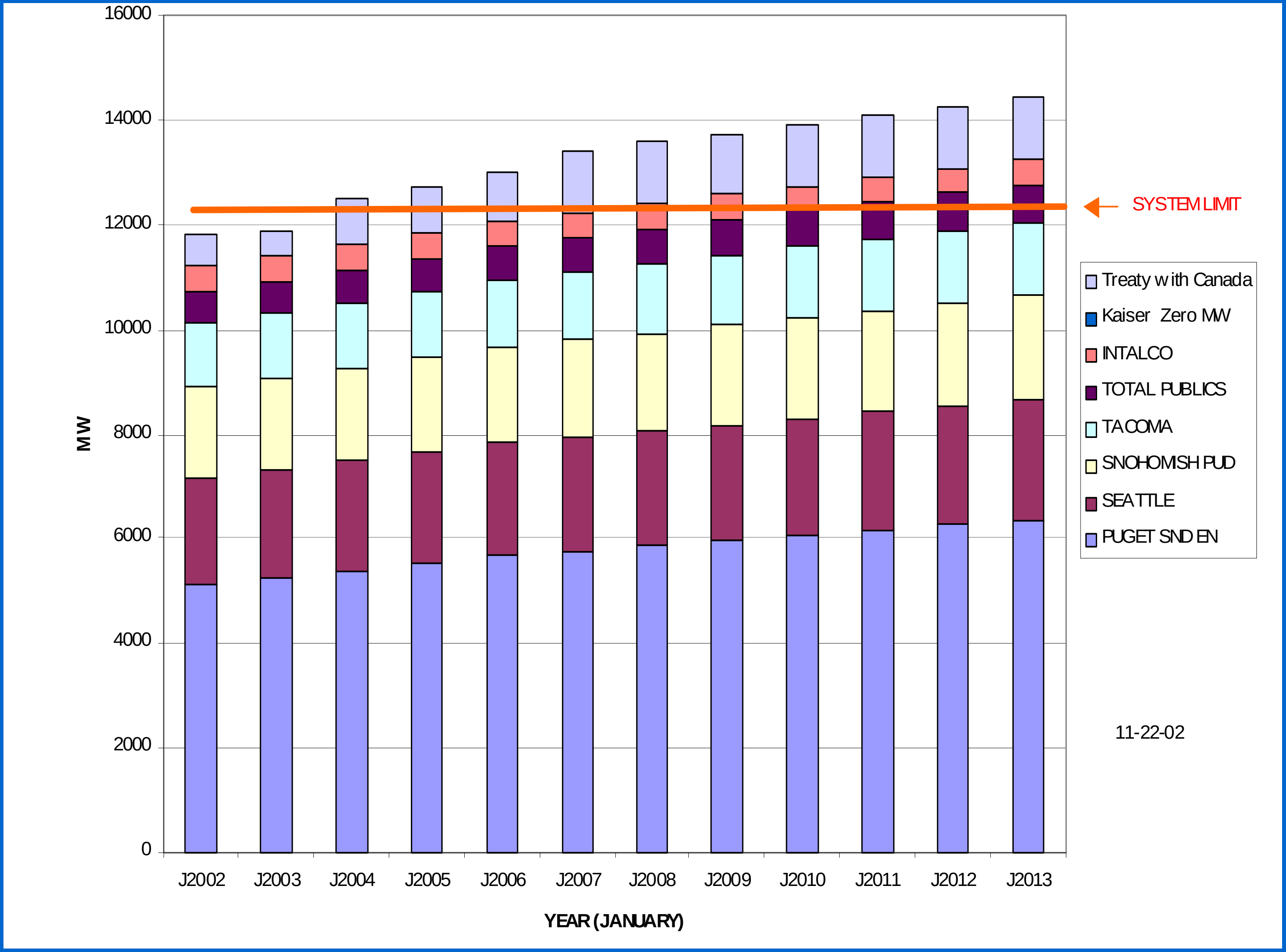
Determination of Peak Demand

- BPA requests “average” forecasts of peak demand from large utilities
- DSI are generally served on a demand basis
  - BPA assumes the peak load = 100% of contract demand
- Canadian Entitlement
  - BPA returned 600MW in 2002, and expects to return 907 MW in 2004, increasing to 1,179MW in 2007
- Local generation
  - Amount of local generation running reduces transmission demand
  - BPA’s load flow studies assume 2,000 MW running

Weather Sensitivities

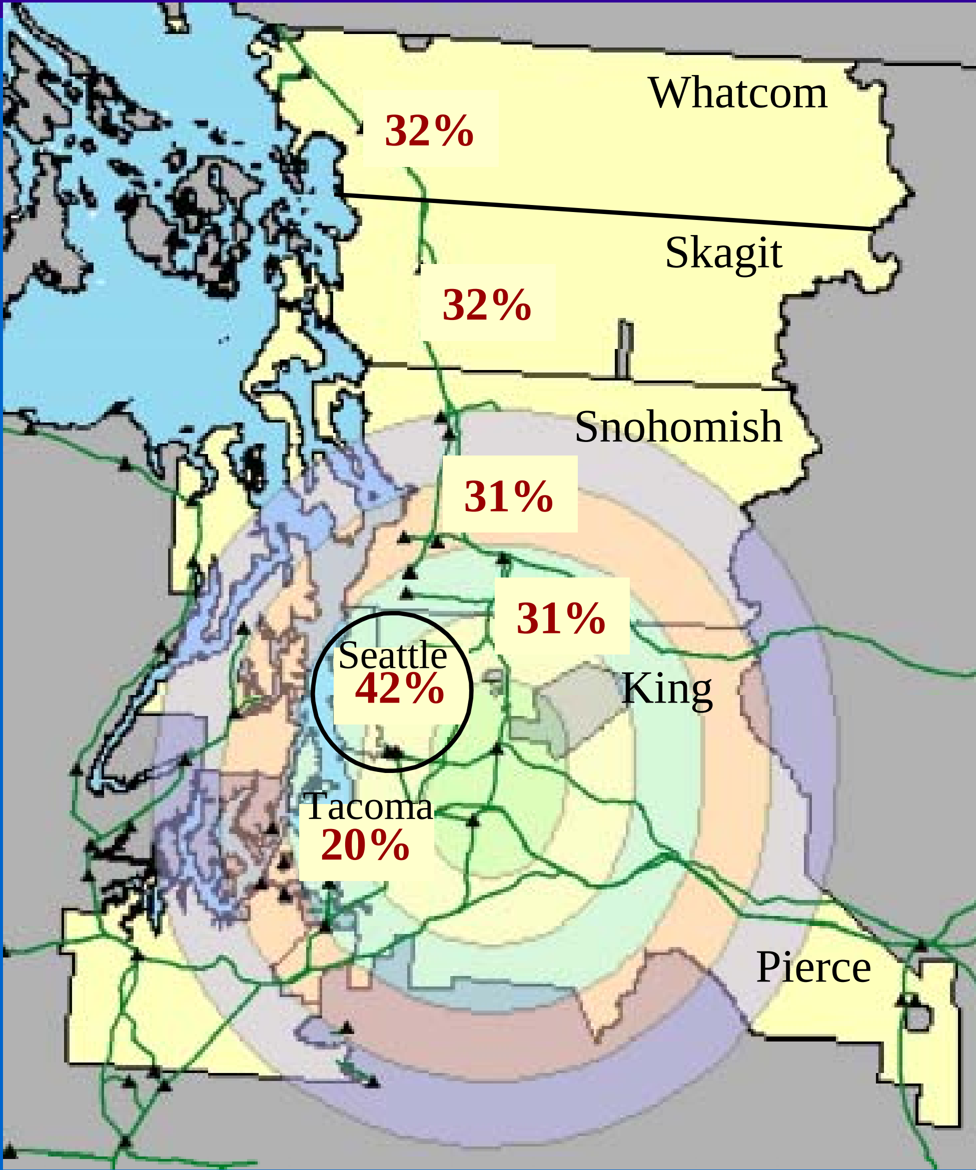
- Utilities adjust "average" winter peak loads upward to reflect a 1-in-20 year 'Arctic Express' weather event
- BPA uses adjustment factors provided by the utilities or based on a study done by Battelle for BPA
  - The adjustment factor averages approximately 17%
    - Depends on types of loads and changes with the composition of loads during the forecast period

The Puget Sound Area

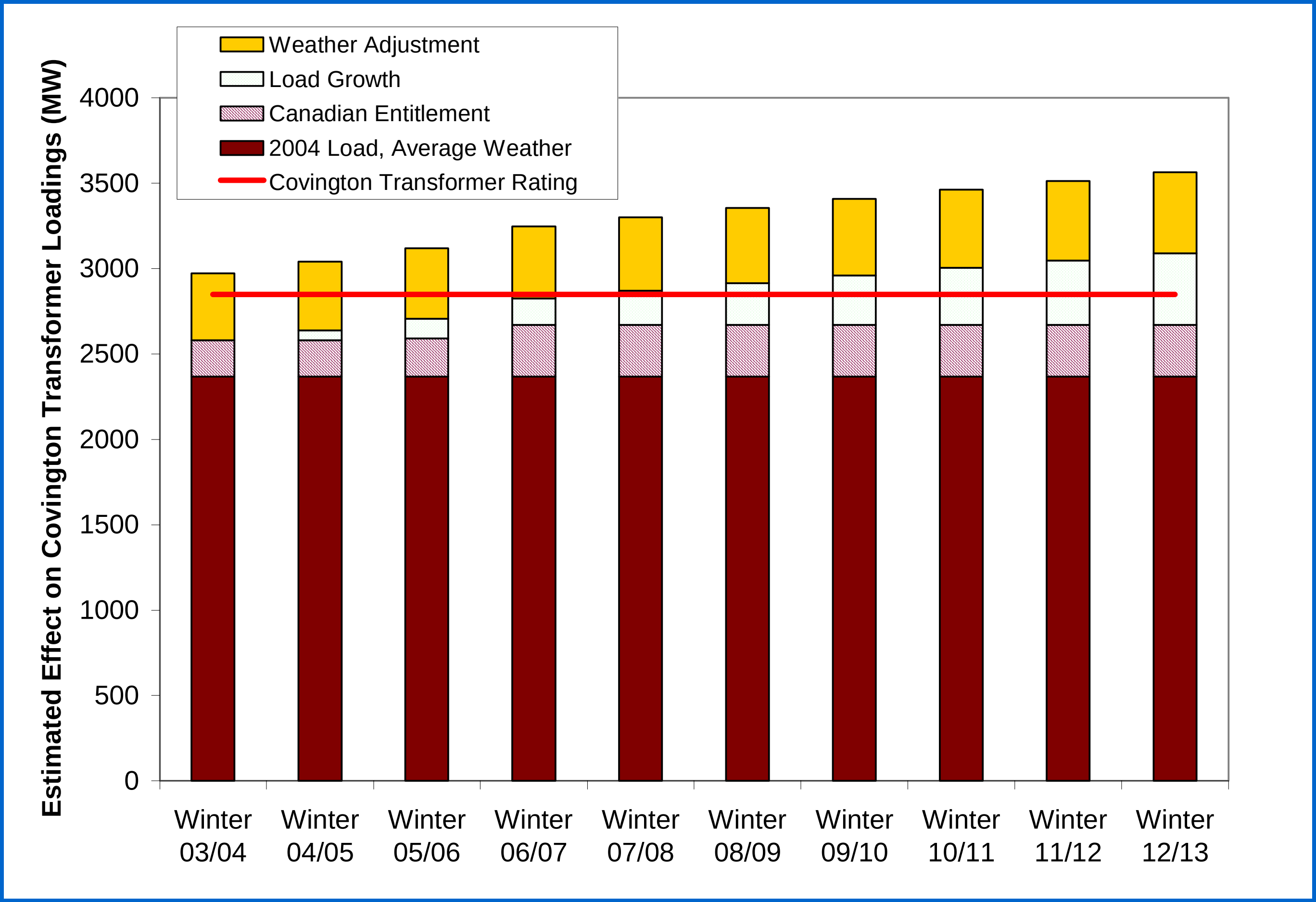


Load Flow Distribution Factors

- Load reduction at different locations will have a different effect on Covington transformer loadings due to network power flow interactions
  - Load weighted average distribution factor across Puget Sound Area is 32%
  - 122MW required at Covington translates to 381MW within the Puget Sound Area



Covington Overload Forecast



122 MW of load reduction required at the Covington transmission substation during the winter of 2003-2004 to prevent an overload on the transmission system and to maintain system reliability during a major system outage. *(Amount increases every year thereafter).*

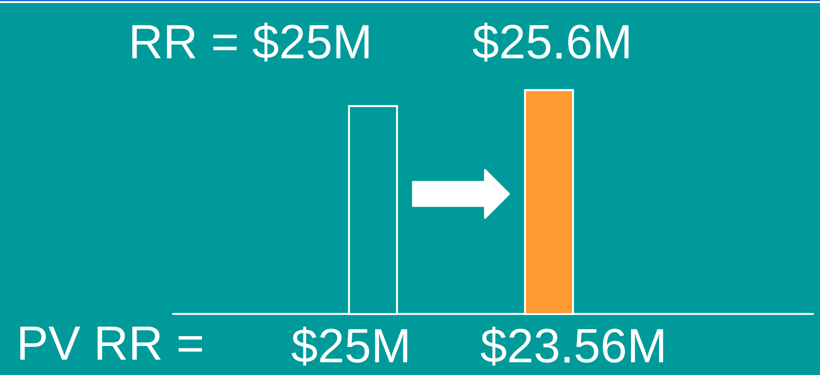
Projected Covington Transformer Bank Overloads, 2004-2013

Year	Maximum Overload (MW)	Number of Hours Overload Occurs
2004	122	10
2005	190	17
2006	269	30
2007	397	51
2008	449	61
2009	505	70
2010	558	86
2011	611	102
2012	664	119
2013	714	135

Calculating the Incentive Payments

Incentive payments based on marginal avoided costs
(The Present Worth Method)

$$\text{Marginal Cost} = \frac{\text{PVRR Base Plan - PVRR Deferred Plan}}{\text{Load Reduction Required for Deferral}}$$



$$\frac{\$1.445M}{122MW} = \$11.84/kW$$

i=2.7%, WACC = 9%

$11.84/kW ($12.25/kW when including annual O&M) is the point at which the incentive payment equals the value of deferral. A load reduction of less than 122MW will not be sufficient to defer the line, therefore avoided transmission cost = zero

Cost-Effectiveness of Alternatives

- Screen for cost-effective alternatives
  – Calculate benefit/cost (B/C) ratios of non-wires technologies and programs
- B/C ratio > 1 indicates the benefits of the alternative are greater than its cost
  – Potentially cost-effective alternative to the transmission line

“Cost effective to whom?”

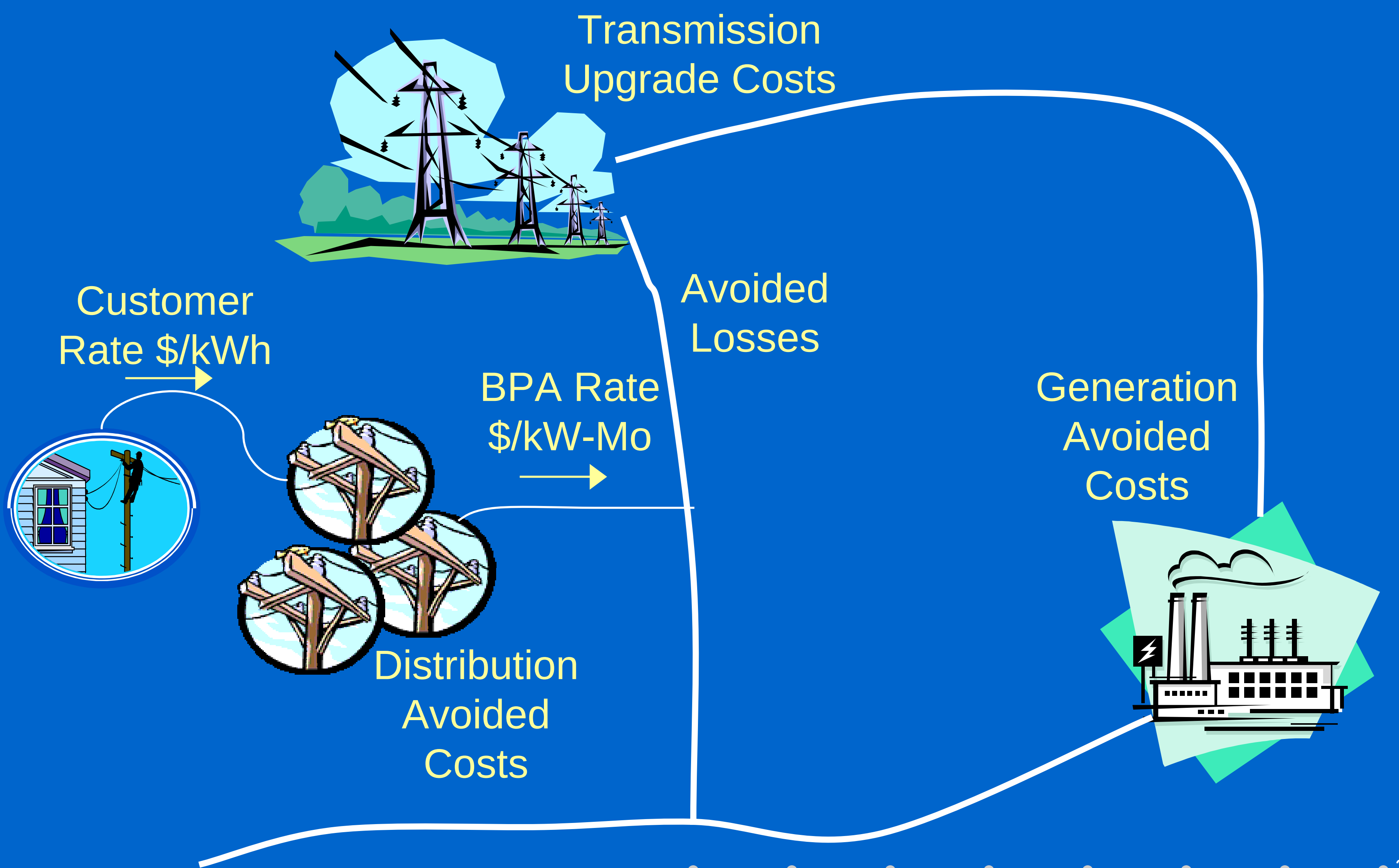
Perspective is Extremely Important

	Societal Focus	Utility Focus
UCT (Revenue Req.)	Too Narrow - Undervalues Benefits to Other Parties	Current Practice - PVRR
RIM (Rates)	Predatory Test for Energy Efficiency	Impact on Rates is Important
TRC (Utility+Customer)	Reasonable, but still ignores environment	Too vague - better for who?
Societal (Comprehensive)	Least cost for society	Requires utility rates to implement social policy
Participant	Narrow, must include all reasons for participation	Used to estimate adoptions or success of RFPs

Perspective for Cost Effectiveness Tests

Tests and Perspective	Program Costs	Program Benefits
RIM Test **BPA TBL**	TBL Incentive TBL Revenue Loss Admin Costs	T Avoided Cost
Utility Cost Test **BPA TBL**	TBL Incentive Admin Costs	T Avoided Cost
TRC Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Societal Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings Environmental Externalities	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Participant Cost Test **Distribution Utility Customers**	Participant Measure / Program Costs	TBL Incentive Dist. Utility Incentive Dist. Revenue Loss
RIM Test **Distribution Utility**	Dist. Utility Incentive Dist. Revenue Loss Utility Admin	Gen Capacity Savings Energy Savings TBL Revenue Loss D Avoided Cost

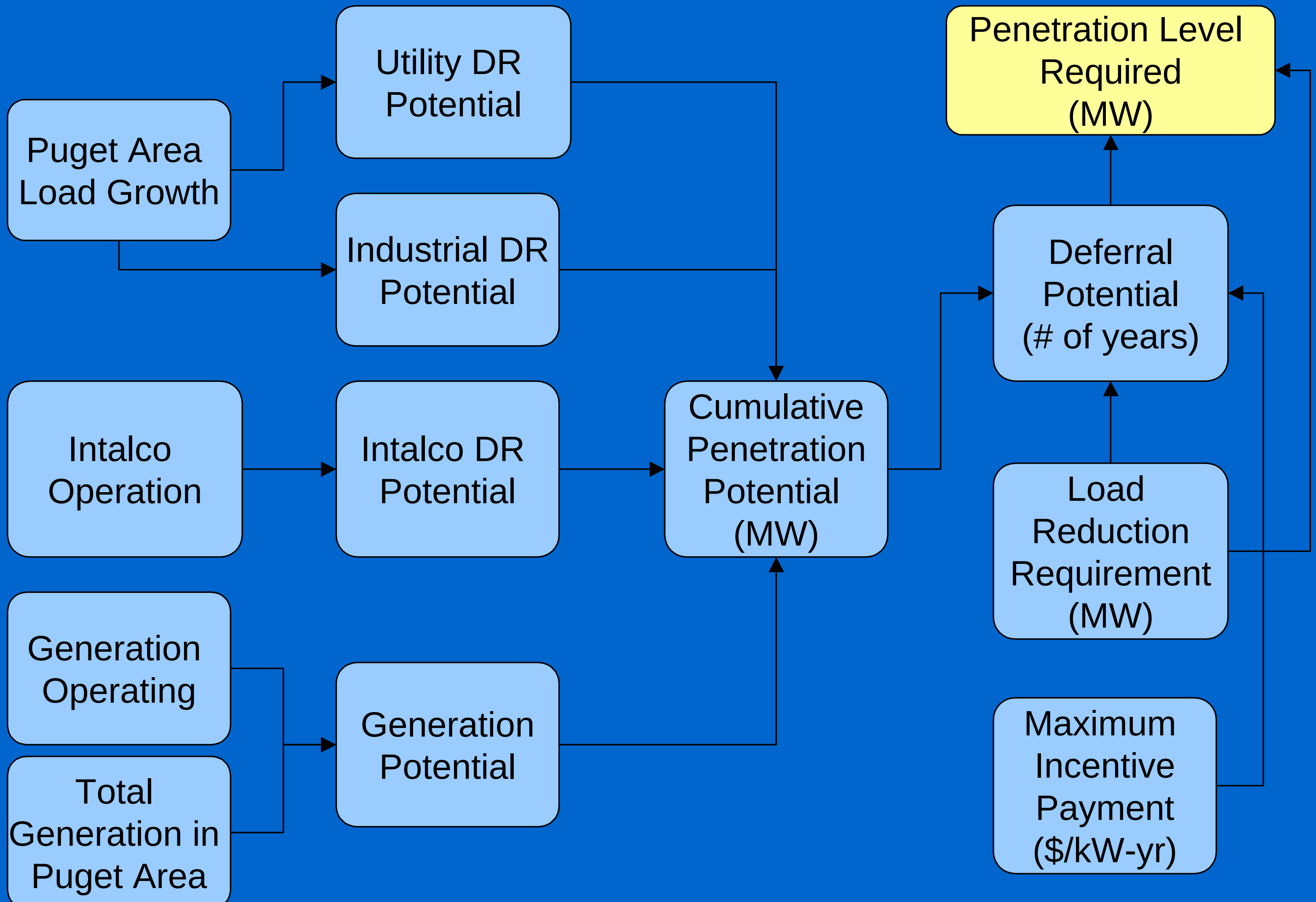
Components of the Economic Model



Reason for the Penetration Analysis

- Timing
  - Initially KEL project was deemed too close to commitment date for a non wires alternative
    - Requires implementation prior to the winter of 2003-2004
- Penetration analyses determine whether alternatives can achieve load reduction within the necessary time frame
  - Targeting less dispersed and larger industrial customers likely to yield better results for load reduction goal at Covington
    - Commercial and residential sectors were not included in the penetration analysis

Required Penetration Level



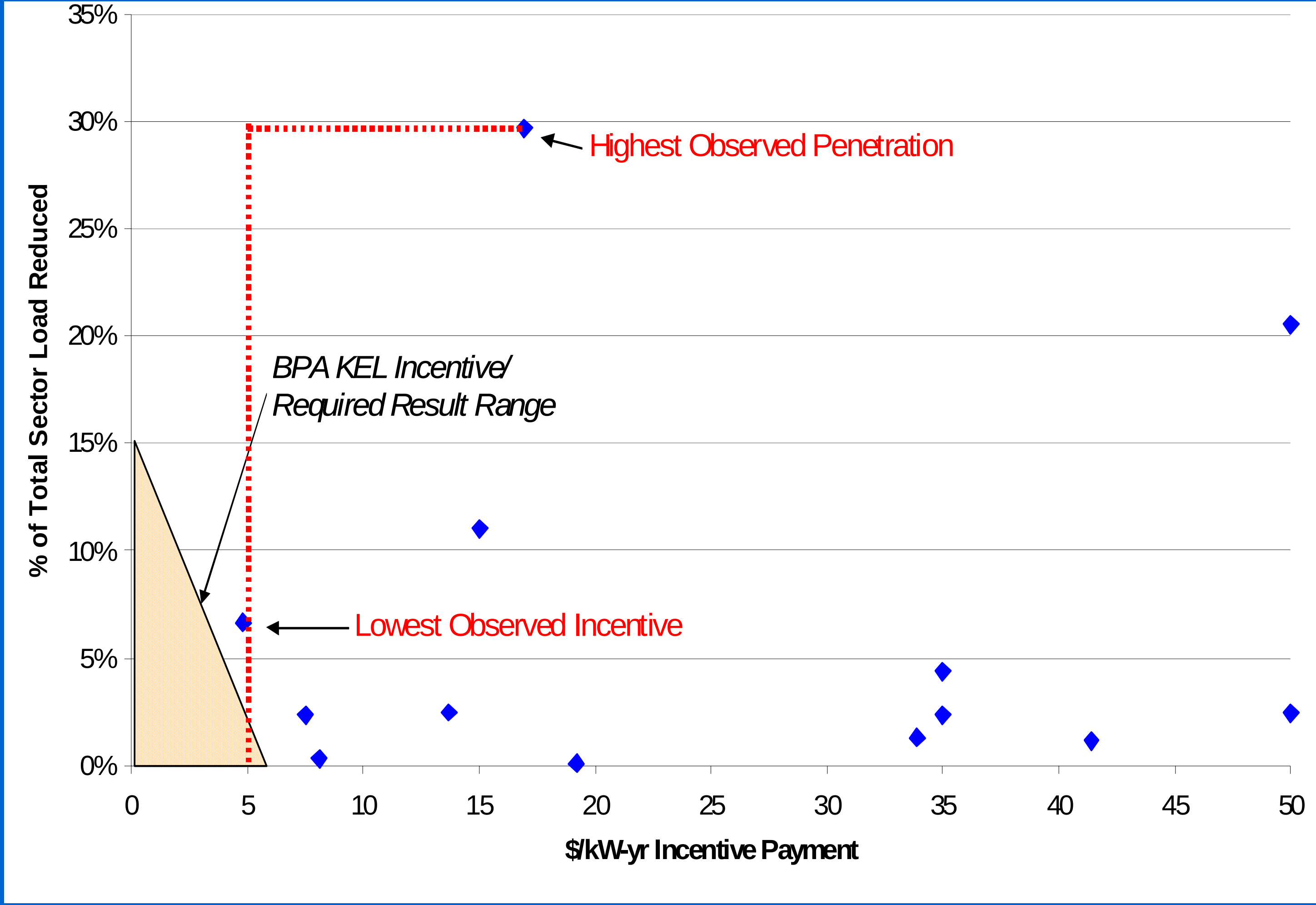
Penetration Assumptions

Potential MW reduction/addition at Covington *Accounting for Load Flow Distribution Factors*		
Demand Response		519 MW
	Intalco	*75 MW*
	*Industrial**	*444 MW*
Additional Generation		70 MW
TOTAL POTENTIAL		**589 MW**

* Industrial potential levels were calculated by approximating the number of industrial customers with over 1MW of load

DR Penetration Potential

Penetration and Incentive Ranges of 13 Utility DR Programs



Summary of Results

Non-Transmission Study Results

- Transmission avoided costs are low
  - $25 million of construction costs and $50,000 of annual O&M costs
    - **$1.5 million** for a one year deferral
    - $12.25/kW-year at Covington or $3.92 /kW-year in the Puget Sound Area based on average load flow distribution factors
- The economic value of the energy loss savings from the line is greater than the cost of the line
  - 11MW reduction of peak losses on the transmission system
    - Annual energy savings of 48,180MWh
    - **$2 million** at a market price of $40/MWh

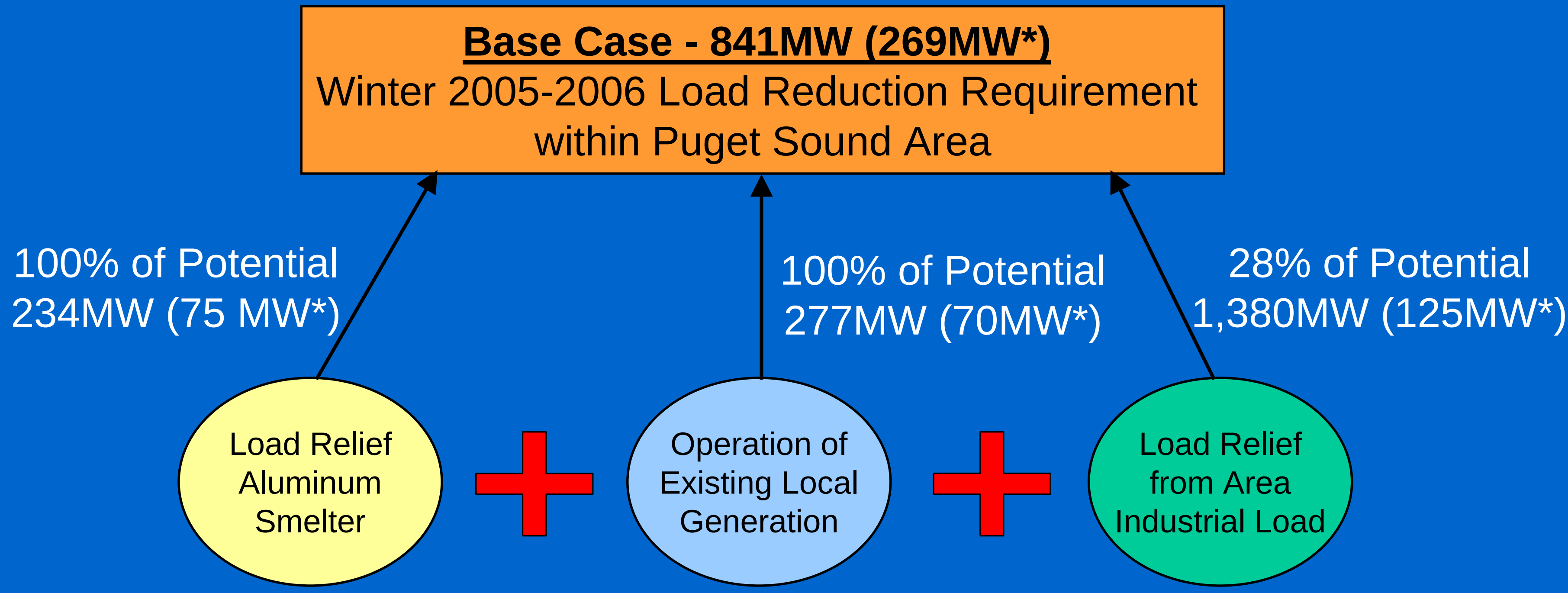
Non-Transmission Study Results

- Demand response is the most cost-effective alternative from a TBL rate perspective
  - DR-DLC focuses load reduction on only the hours when needed for system reliability
- However, incentive levels are low compared to other programs
  - **$3.92/kW-yr** available for DR-DLC incentives
  - Range of incentives from surveyed programs: **$4.8-$128/kW-yr**

Non-Transmission Study Results

A high level of load reduction and additional generation is required to defer the line

Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line



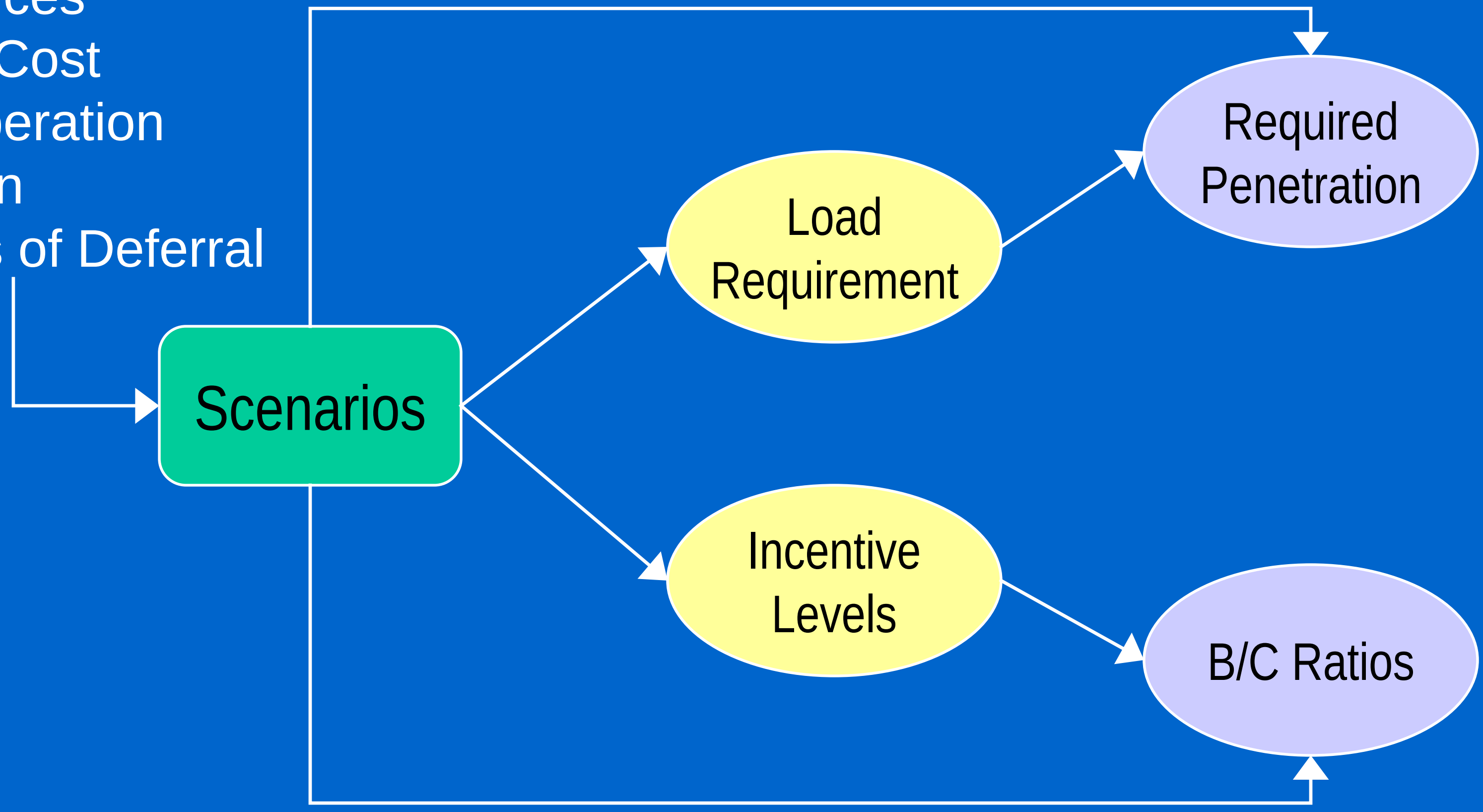
(xMW*) = reduction at Covington

Scenarios

Scenarios

Variables Driving the Scenarios

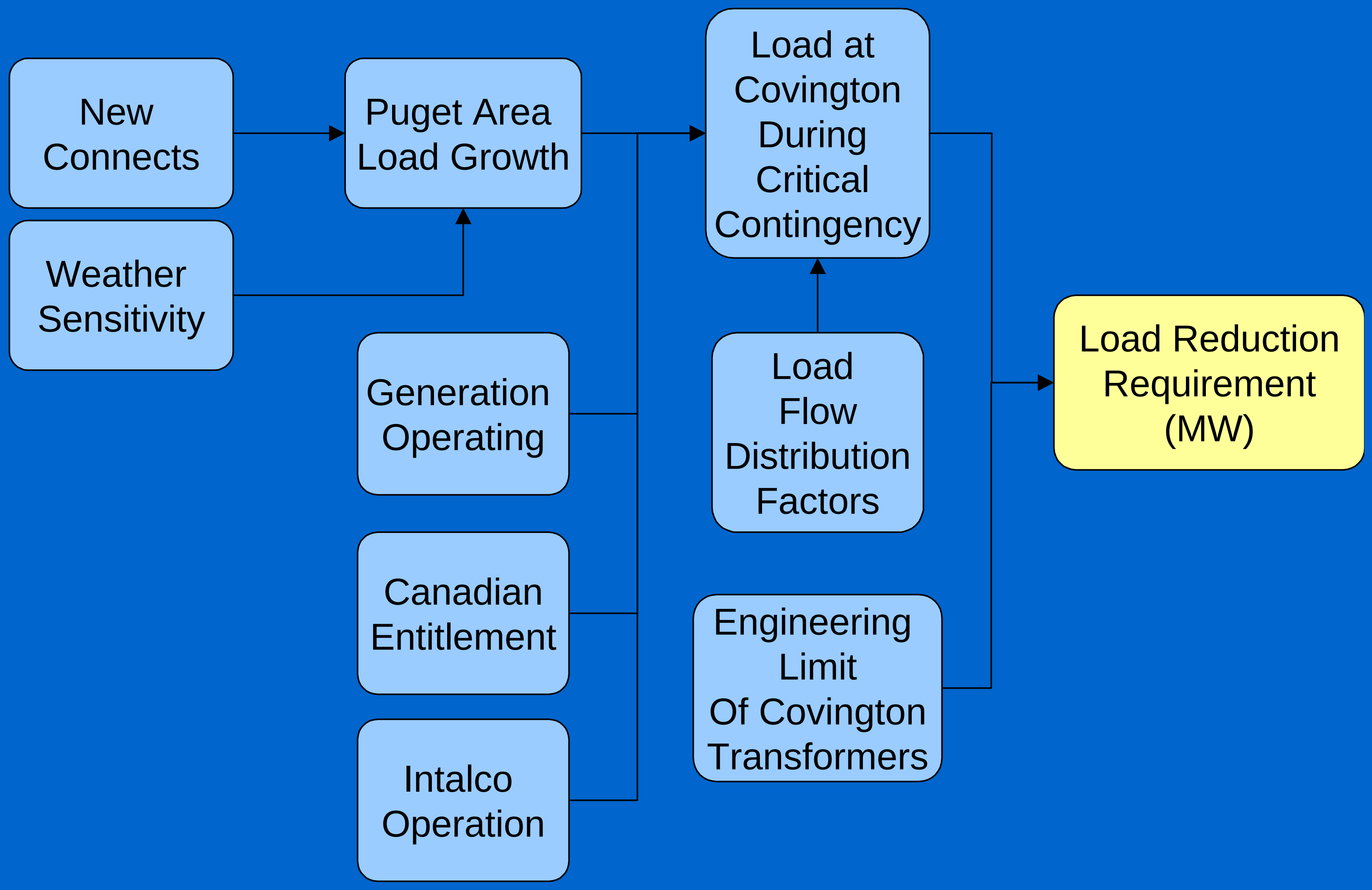
Load Growth
Market Prices
KEL Line Cost
Intalco Operation
Generation
# of Years of Deferral



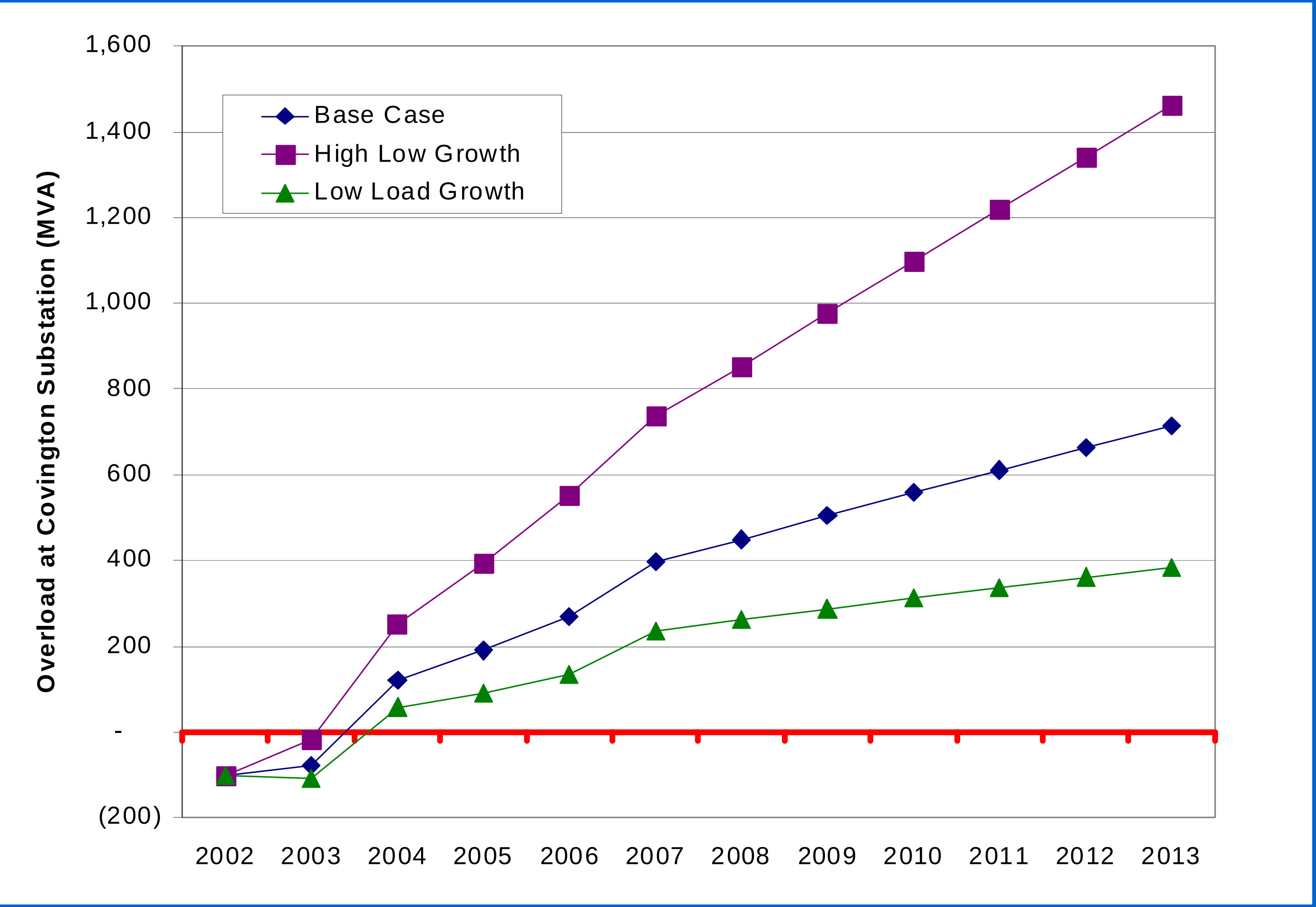
Three Scenarios Investigated

	Base Case	'Optimistic' Case	'Pessimistic' Case
Load Growth	Base: 1.5% growth	Low: 0.8% growth	High: 3% growth
Generation Operating	Base: 2,000 MW	High: 2,200 MW	Low: 1,700 MW
KEL Line Cost O&M	Base: $25 Million Base: $50,000/yr	Base	Base
Avoided Costs	Base: $5.70/kW-yr	High: $18.68/kW-yr	Low: $2.38/kW-yr
Avoided Line Loss Savings	Base: $7.34/kW-yr	High: $24.04/kW-yr	Low: $3.06/kW-yr
Market Price	Base: $40/MWh	High: $52/MWh	Low: $29/MWh

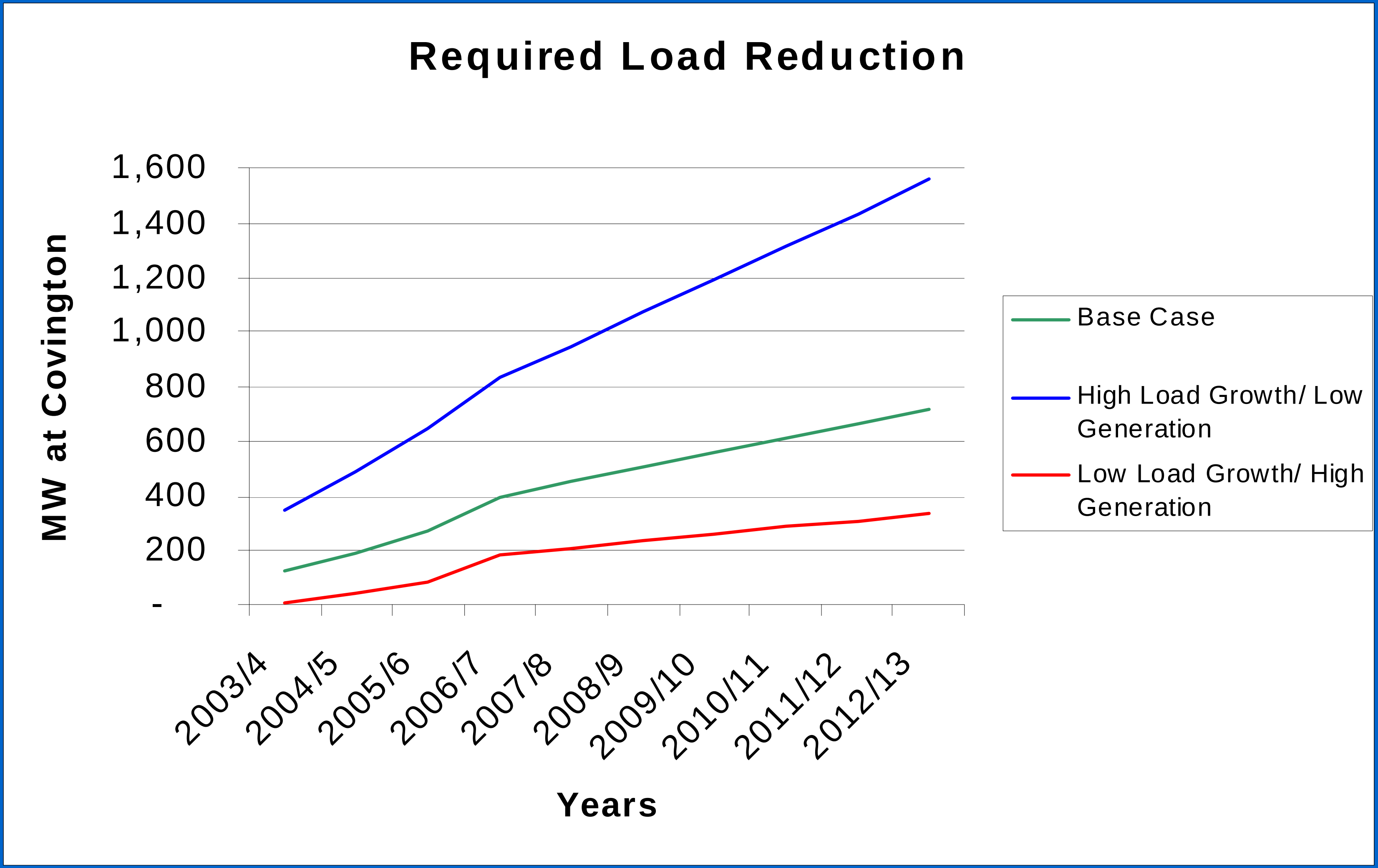
Estimating Load Requirement



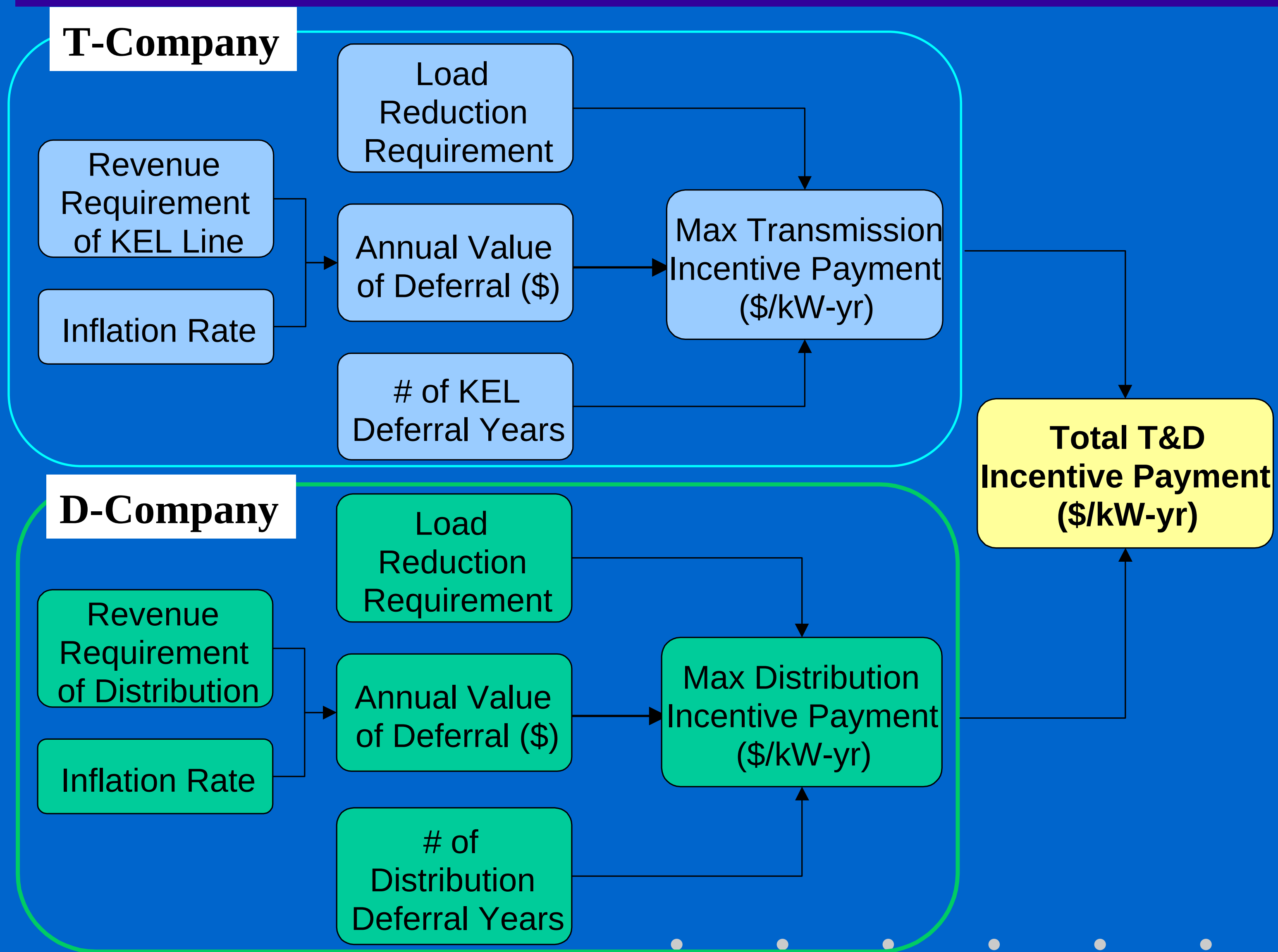
Load Growth Sensitivity Cases



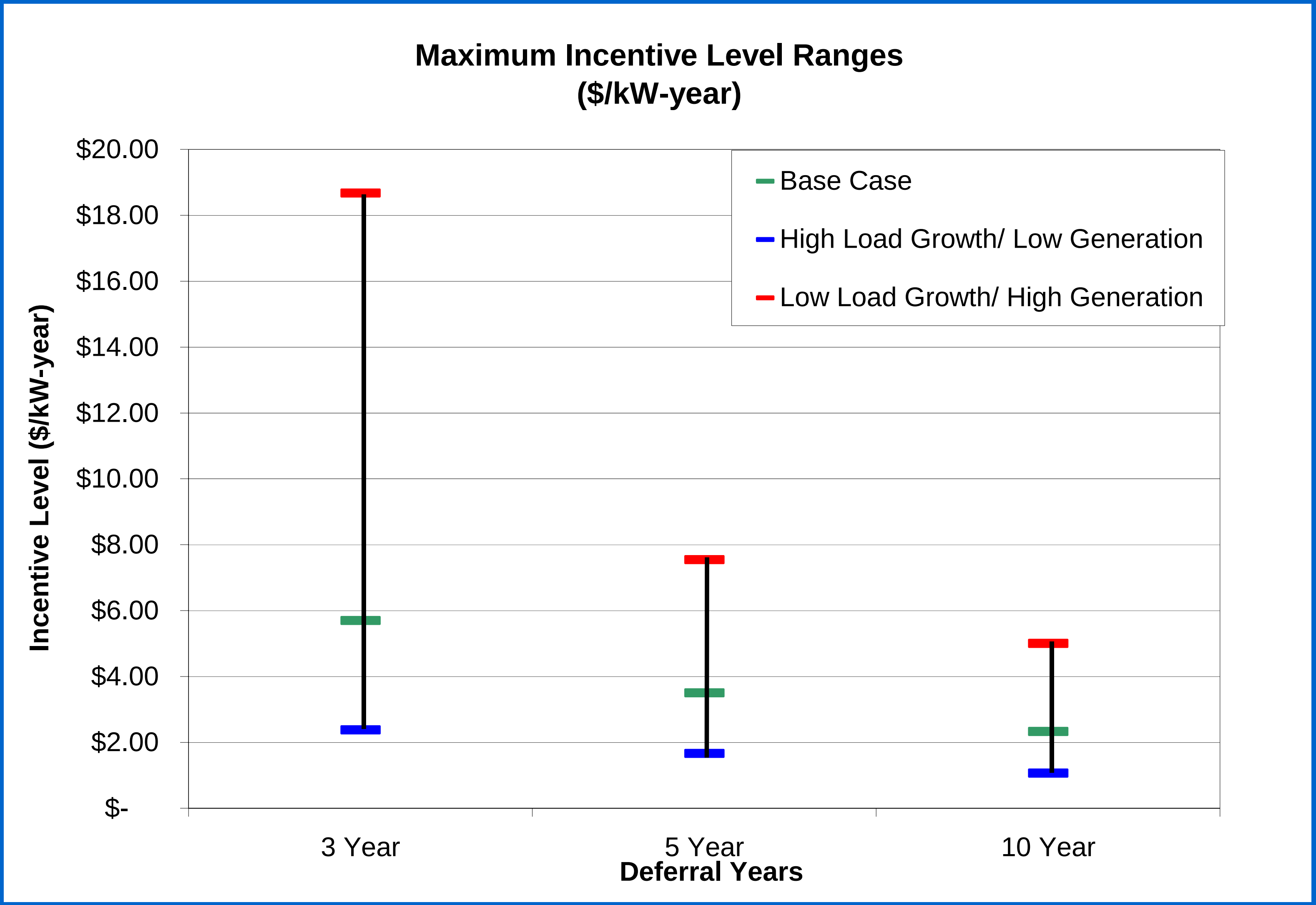
Required Load Reduction



Estimating Incentive Levels



Maximum Incentive Level Ranges



Max Incentive is per kW at Covington Substation

Base Case Results

A high level of load reduction and additional generation is required to defer the line

Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line

Base Case - 841MW (269MW*)
Winter 2005-2006 Load Reduction Requirement within Puget Sound Area

100% of Potential
234MW (75 MW*)

Load Relief Aluminum Smelter

+

100% of Potential
277MW (70MW*)

Operation of Existing Local Generation

+

28% of Potential
1,380MW (125MW*)

Load Relief from Area Industrial Load

(xMW*) = reduction at Covington

Optimistic Case Results

Scenario analysis indicates alternatives could be cost effective if demand is lower than forecast

Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line

Optimistic Case - 256MW (82MW*)
Winter 2005-2006 Load Reduction Requirement within Puget Sound Area

100% of Potential
234MW (75MW*)

Load Relief Aluminum Smelter

+

11% of Potential
277MW (7MW*)

Operation of Existing Local Generation

OR

2% of Potential
1,380MW (7MW*)

Load Relief from Area Industrial Load

(xMW*) = reduction at Covington

Required Penetration Levels by Scenario Measured at Covington

Scenario	DR & Generation Penetration	Year 3 % Penetration Required	MW
Base Case		**269**	
	Industrial	28%	125
	Intalco	100%	75
	Generation	100%	70
Pessimistic		**645**	
	Industrial	Not Enough Available	
	Intalco		
	Generation		
Optimistic		**82**	
	Industrial	0%*	-
	Intalco	100%	75
	Generation	11%	7

* In the optimistic case, Intalco plus a 2% industrial penetration (7MW) will also be sufficient to defer the KEL line.

Detailed Results

Base Case Results

No cost-effective measures from both the TBL RIM perspective and the Participant Cost test

	DSM	DG	DR	G
Alternative	Single Family Heating	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.0004	0.01	1.00	1.00
Utility Cost	0.02	1.00	1.00	1.00
TRC Cost	1.94	0.56	0.56	1.56
Societal Cost	2.40	0.50	0.60	1.10
Participant Cost	2.20	0.56	0.78	0.99
RIM-LDC	0.71	1.03	0.80	Not Effected

Optimistic Case Results

DR and G looks cost-effective from both the TBL RIM perspective and the Participant Cost test

	DSM	**DG**	**DR**	**G**
Alternative	HEATING - Single Family Heat Pump - PTCS System O&M	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.12	0.02	1.00	1.00
Utility Cost	No Utility Costs	1.00	1.00	1.00
TRC Cost	1.13	0.73	0.70	2.03
Societal Cost	1.33	0.66	0.73	1.44
Participant Cost	2.27	0.56	1.14	1.30
RIM-LDC	0.54	1.28	1.05	Not Effected

Pessimistic Case Results

No cost-effective measures from both the TBL RIM perspective and the Participant Cost test

	DSM	**DG**	**DR**	**G**
Alternative	HEATING	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.00	0.00	1.00	1.00
Utility Cost	0.00	1.00	1.00	1.00
TRC Cost	1.65	0.41	0.23	1.13
Societal Cost	2.04	0.37	0.25	0.80
Participant Cost	2.20	0.56	0.37	0.72
RIM-LDC	0.56	0.82	0.58	Not Effected

DSM Results

Additional DSM Assumptions for Scenarios

	Base	Optimistic	Pessimistic
Incentive Basis	100%	100%	100%
BPA % of Incentive	50%	0%	100%
Basis of kW Load Reduction	System	Local	System

Number of DSM Programs that Are Cost Effective from Each Perspective

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Base	0	0	1034	1179	1523	1
Optimistic	0	0	1151	1263	1523	53
Pessimistic	0	0	929	1063	1523	0

DSM Demand and Energy Savings

	System KW Savings	Annual kWh Savings	kWh/kW	Load Reduction Requirement for Year 1 (MW)	Expected Annual MWh Savings
All Programs	0.3291	3,933	11,950	122 MW at Covington or 381 MW within the Puget Sound Area	4,556,115
Top 10 for lowest kWh/kW ratio (1)	1.9771	6,674	3,376		1,287,005
Top 10 for $/kW (2)	4.8442	60,016	12,389		4,723,424
Top 10 for $/kWh (3)	4.8228	61,335	12,718		4,848,650

(1) Residential and small commercial heating programs
(2) Industrial efficient motors plus one residential heating measure
(3) Industrial efficient motors

Required DR/DLC and Existing Generation Penetration Levels for Load Growth Scenarios

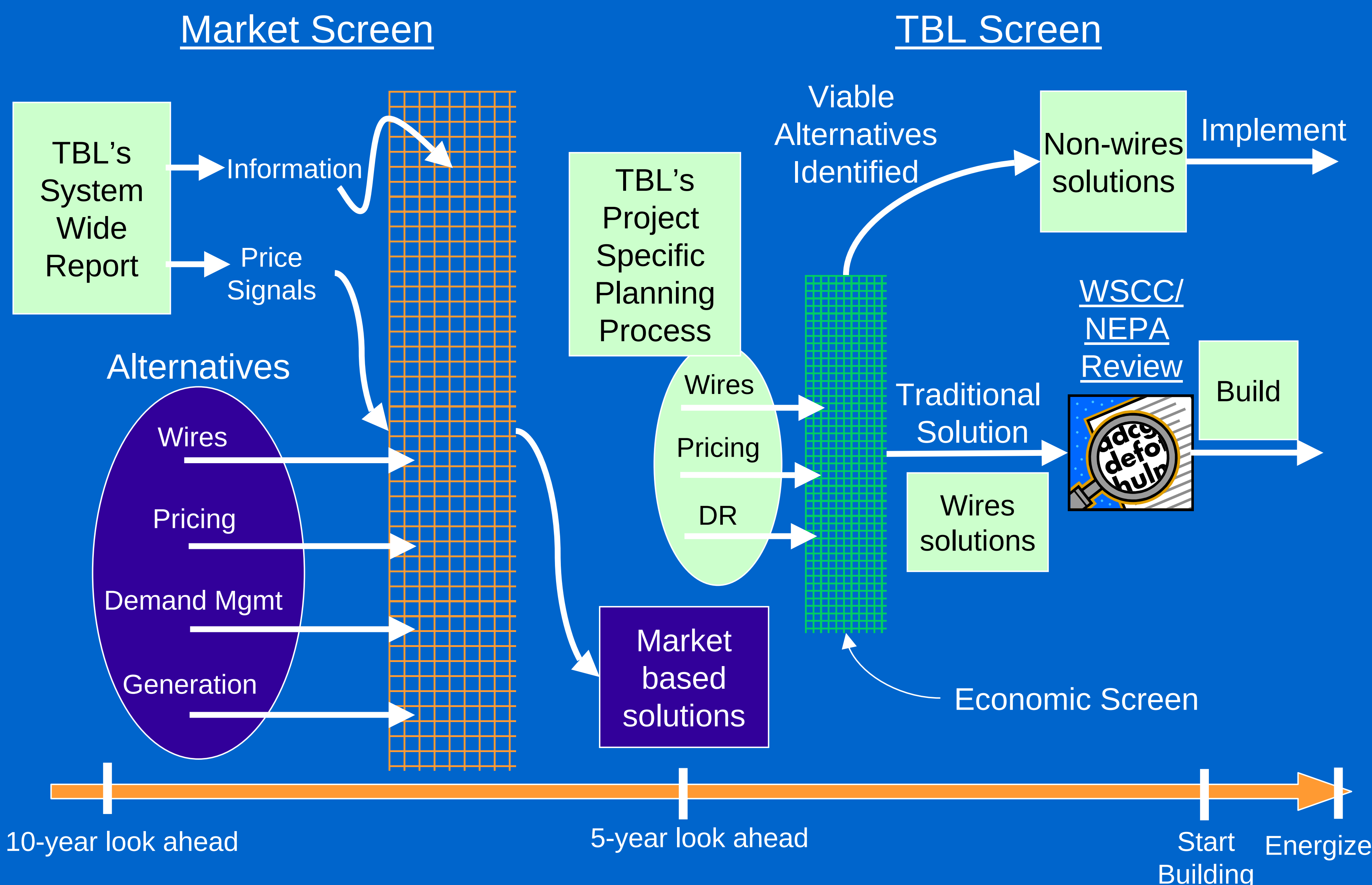
Scenario	DR & Generation Penetration	Year 1		Year 2		Year 3	
		% Penetration Required	MW	% Penetration Required	MW	% Penetration Required	MW
Base Case		**122**		**190**		**269**	
	Industrial	0%	-	10%	45	28%	125
	Intalco	100%	75	100%	75	100%	75
	Generation	68%	47	100%	70	100%	70
High Load Growth/ Low Generation		**346**		**488**		**645**	
	Industrial	45%	201	77%	343	Not Enough Available	
	Intalco	100%	75	100%	75		
	Generation	100%	70	100%	70		
High Load Growth/ Base Generation		**252**		**394**		**551**	
	Industrial	24%	107	56%	249	92%	406
	Intalco	100%	75	100%	75	100%	75
	Generation	100%	70	100%	70	100%	70
Low Load Growth/ Base Generation		**58**		**91**		**135**	
	Industrial	0%	-	0%	-	0%	-
	Intalco	100%	75	100%	75	100%	75
	Generation	0%	-	24%	16	86%	60
Low Load Growth/ High Generation		**5**		**39**		**82**	
	Industrial	0%	-	0%	-	0%	-
	Intalco	100%	75	100%	75	100%	75
	Generation	0%	-	0%	-	11%	7

Conclusions

Conclusions

- High load reduction or additional generation required
- Transmission avoided costs are low
- Incentive levels are low in comparison to other utility programs
- Demand response is the most cost-effective from TBL rate perspective
- Alternatives to line construction could be feasible if demand is lower than forecasted

Long-Term Planning Process



Base Case Max. Incentive Levels

Minimum Contract Length	1 Year	2 Year	3 Year	4 Year	5 Year
Minimum Total MW Required	122.00	189.93	269.20	397.20	449.39
Maximum Incentive	$ 1,494,954	$ 2,906,393	$ 4,236,252	$ 5,489,249	$ 6,669,824
$/kW (PV Contract Payments)	$ 12.25	$ 15.30	$ 15.74	$ 13.82	$ 14.84
$/kW-yr (Level Annual Payments)	$ 12.25	$ 7.98	$ 5.70	$ 3.91	$ 3.50

Assumptions:

- MW Requirement at Covington
- $25 Million Avoided Investment Cost